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RAILROAD COMMISSION OF TEXAS

OFFICE OF GENERAL COUNSEL

RULE 37/38 CASE NO. 0229028 ET AL.

APPLICATIONS OF BP AMERICA PRODUCTION COMPANY FOR EXCEPTIONS TO STATEWIDE RULES 37 AND/OR 38 FOR TWENTY WELLS ON ITS PRICE ET AL., BRANNON "C", W. N. PRICE, PRICE, PRICE "B", AND SWENY LEASES, TEXAS HUGOTON FIELD, SHERMAN COUNTY, TEXAS

APPEARANCES:

FOR APPLICANT:	**APPLICANT:**
A. Andrew Gallo Sandra B. Buch John G. Soule Michael Holmes W. D. Griffin	BP America Production Company
FOR PROTESTANTS:	
W. Timothy George Joe Cochran Richard Strickland	Phillips Petroleum Company
Matt Sjoberg	Travelers Oil Company

PROPOSAL FOR DECISION

PROCEDURAL HISTORY

APPLICATIONS FILED:	July 23, 2001
HEARING DATES:	April 22-May 1, 2002
HEARD BY:	James M. Doherty, Hearings Examiner Donna Chandler, Technical Examiner
BRIEFING CLOSED:	June 21, 2002
PFD CIRCULATION DATE:	April 14, 2003

STATEMENT OF THE CASE

Between July 23-31, 2001, Amoco Production Company filed applications requesting exceptions to either or both of Statewide Rule 37 and Statewide Rule 38 to drill a total of thirty-nine (39) wells on its Flores, Flores "86", Flores "95", Huber Et Al., Price Et Al., Brannon "C", W. N. Price, Price "B", Price and Sweny Leases, Texas Hugoton Field, Sherman and Moore Counties, Texas. Subsequent to the filing of the applications, applicant's name was changed to BP America Production Company, and applicant is hereinafter referred to as "BP". The applications were protested by Phillips Petroleum Company ("Phillips") and Travelers Oil Company ("Travelers"). A prehearing conference regarding the applications was held on October 5, 2001.

As a result of the prehearing conference and agreement of the parties, the 39 applications were consolidated into two groups, thereafter commonly referred to as the "Flores" group and the "Price 'D'" group, for purposes of hearing and preparation of proposals for decision. The "Flores" applications were heard during the period March 4-14, 2002, and are the subject of a separate proposal for decision. The "Price 'D'" applications, which are the subject of this Proposal for Decision, were heard by the same examiners during the period April 22-May 1, 2002.

The 20 Price "D" applications were heard over a period of 8 hearing days. The testimony given during the Price "D" hearing is transcribed in 8 volumes of transcript containing 1,439 pages, and 374 exhibits were offered into evidence.

Field rules for the Texas Hugoton Field ("subject field") provide for spacing of 1,250 feet from any property line, lease line or subdivision line and 2,500 feet from any well on the same tract completed in or drilling to the same horizon. The field rules also provide for 640 acre density.

BP's Price Et Al., Brannon "C", W. N. Price, Price, Price "B", and Sweny Leases (hereinafter sometimes referred to collectively as the "subject leases" or "Price 'D' Leases") now have the maximum number of producing wells permitted by the 640 acre density rule governing the Texas Hugoton Field. BP requests exceptions to Statewide Rule 38 to drill 15 additional wells on its Price Et Al. Lease, and 1 additional well on each of its Brannon "C", W. N. Price, Price, Price "B", and Sweny Leases. BP also requests Rule 37 exceptions for 7 of the proposed wells on the Price Et Al. Lease, and for the proposed wells on the Brannon "C", W. N. Price, Price, and Price "B" Leases.

Appendix 1 to this Proposal for Decision summarizes the 20 applications in the "Price 'D'" group by docket number, proposed well number, lease and lease acres, location data, type of exception(s) requested, proposed spacing to lease lines and between wells (feet), and reason for the requested exception(s). Appendix 2 to this Proposal for Decision (also BP Exhibit 15 herein) is a well status and ownership map of the Price "D" Lease Area which shows BP's subject leases, a ring of sections around the subject leases (sometimes hereinafter referred to as the "halo area"), lease ownership, existing wells and their status, cumulative recovery of existing wells, and the location of BP's proposed wells (indicated by red dots). Phillips is shown as the operator of offsetting tracts to the northeast, east, southeast, south, west, and northwest of BP's subject leases, as well as of window tracts interior to the subject leases. Travelers is shown as the operator of a tract to the northwest of BP's subject leases.

POSITIONS OF THE PARTIES

Applicant's Position

BP argues that approval of the BP applications is necessary to prevent waste and to prevent confiscation.

BP asserts that it proved that waste will occur unless its proposed Rule 37/38 wells are permitted in that the evidence shows: (1) existing wells will not produce remaining recoverable reserves beneath the Price "D" Leases; (2) new wells drilled in the vicinity of existing wells will produce significant volumes of incremental reserves; (3) new wells do not interfere with production from nearby wells; and (4) areas of low recovery on the Price "D" Leases are different from other areas of the Texas Hugoton Field, indicating unique or unusual circumstances.

BP asserts that approval of its applications is necessary to prevent confiscation in that: (1) under Texas law, BP is entitled to recover the reserves underlying its tracts, and any deprivation of that right equates to confiscation; and (2) existing wells on the Price "D" Leases will not permit BP to recover its fair share of the hydrocarbons beneath the leases.

BP also argues that its proposed well locations are reasonable.

Protestants' Position

Phillips argues that BP failed to show that the proposed Rule 37/38 wells are necessary to prevent waste or to prevent confiscation.

Phillips says that BP did not prove that its proposed wells are necessary to prevent confiscation because: (1) BP did not reliably establish the volume of currently recoverable reserves beneath the Price "D" Leases or that existing wells will not recover reserves beneath the leases; (2) future recovery by existing wells on the Price "D" Leases will out pace recovery by wells on surrounding tracts; and (3) existing wells on the Price "D" Leases already take gas from adjoining tracts.

Phillips asserts that BP did not prove that its proposed wells are necessary to prevent waste in that: (1) there are no unique or unusual conditions beneath the Price "D" Leases that distinguish the areas where the wells are proposed to be drilled from other areas of the Texas Hugoton Field; (2) there is no reasonable basis for BP's proposed well locations; (3) BP did not reliably prove the volume of recoverable gas in place beneath the Price "D" Leases; and (4) BP did not reliably prove that existing wells on the Price "D" Leases will not recover the reserves beneath the leases.

Travelers says in its brief that it is the operator of 31 wells in the Texas Hugoton Field and is concerned with net uncompensated drainage which would result to Travelers if BP's applications were approved. Travelers argues that BP did not prove waste in that it failed to show unusual conditions beneath the Price "D" Leases. In addition, Travelers argues that BP did not prove confiscation in that the evidence shows that existing wells on the Price "D" Leases are draining reserves from surrounding leases and will continue to do so.

DISCUSSION OF THE EVIDENCE

APPLICANT'S EVIDENCE

BP's evidence pertaining to reservoir engineering mainly was presented by W. D. "Bill" Griffin ("Griffin"), a consulting petroleum engineer who was formerly employed with Amoco Production Company during 1972-2000. Griffin holds a bachelor's degree in chemical engineering from Texas Tech University and is a registered professional engineer with experience in working with carbonate reservoirs. BP's geological and petrophysical evidence primarily was presented by Dr. Michael Holmes ("Dr. Holmes"), an oil and gas consultant. Dr. Holmes has a PhD in geology from the University of London and a Master's degree in petroleum engineering from the Colorado School of Mines, where he does invitational teaching. Dr. Holmes has been a guest lecturer at the University of Brunei and has had experience in working with carbonate reservoirs.

Griffin

(a) Background

The Texas Hugoton Field was discovered in 1918. It lies immediately to the north of the Panhandle West Field and covers the northernmost portion of Moore County, most of Sherman County, and the western portion of Hansford County. The formations in the field which are of interest to BP are the Herington, Upper Krider, and Lower Krider, which are correlative to the Brown Dolomite in the Panhandle West Field. There are some completions in the Winfield formation on the Price "D" Leases, but much of the porosity in the Winfield is water bearing.

Typical depth of the Texas Hugoton Field in the Price "D" area is from 3,000' to 3,500'. The field is a non-associated, prorated gas field. Current field rules for the field were established in 1948. These rules provide for 1,250'/2,500' spacing and 640 acre density. BP presented evidence of field rules adopted since 1990 for other area fields providing for 640 acre and optional 320 acre density, but acknowledged that field rules for the Panhandle West Field provide for 640 acre density. BP does not contend that optional 320 acre density should be adopted for the Texas Hugoton Field.

The Texas Hugoton Field covers approximately 600,000 acres. Of total acreage in the field, Phillips is operator of about 47%, BP is operator of about 22%, and Chesapeake is operator of about 3.5%. These are the three largest operators in the field based on acreage, and there are 64 other operators which operate the remaining 27.5% of the field's acreage. BP's Price "D" Leases are located in Sherman County in the southern portion of the field, reasonably proximate to the northern boundary of the Panhandle West Field and about 4 miles north of BP's Flores Lease. The Price "D" Leases encompass about 23,000 acres. At the time of the hearing, in these dockets, in the Flores Lease dockets, and in two other dockets then pending, BP was seeking Rule 38 exceptions for wells on about 20% of its acreage in the Texas Hugoton Field.

BP's Cartrite Lease lies between its Flores and Price "D" Leases. In the year 2000, BP had success in drilling a replacement well on the Cartrite Lease, which peaked its interest in the potential for drilling additional infill wells on the Flores and Price "D" Leases. This replacement well, the Cartrite No. 3, came in with a pressure of 112 psi, as compared to original reservoir pressure of about 450 psi, but at a producing rate about 4 ½ times the rate of any of the neighboring wells in the Cartrite Lease area. In June 2000, the Cartrite No. 3 produced a little more than a million cubic feet of gas per day. Cumulative production for this well for 2000-2001 was 487,175 MCF, and, according to rate versus time plots presented by Griffin, the well has already produced the combined volume of gas that would have been recovered by the wells that it replaced. The Cartrite No. 3 continues to produce about 600 MCF per day, and Griffin believes the well will recover significant incremental reserves.

Wells in the Price "D" Leases area (including the "halo" area) are producing at capacity, for the most part with flowing tubing pressures of less than 5 psig. The producing rate for most wells is low. Daily producing rates for 2001 mapped by Griffin show that daily rates for wells on the Price "D" Leases range from 40 MCFD to 216 MCFD, and daily rates for wells in the halo of sections surrounding the Price "D" Leases range from 5 MCFD to 281 MCFD. Given these low rates, Griffin does not believe that wells are draining 640 acres.

(b) Basis for Proposed Well Locations

Excluding replacement wells drilled in the 1990's, most area wells were drilled in the 1940's or early 1950's, and no conventional electric logs are available for the older wells. Although conventional electric logs were obtained for about 15 newer wells on or interior to the Price "D" Leases, Griffin concluded that there was insufficient log coverage to do a conventional pore volume analysis for the Price "D" Leases and decided on other methodology for his evaluation of whether wells are draining the area.

Area wells drilled in the late 1940's and early 1950's were completed through the Brown Dolomite with cable tools. Cable tool rigs were used because formation bottomhole pressure was not sufficient to support the column of drilling mud normally used in rotary tool drilling. Completion reports (Form 2 Well Record) filed by cable tool drillers contain observations pertaining to shows of gas and rock types seen at various depths while drilling, and record depths of the producing section from top to bottom for each well. A contour map of the top of the formation as shown by depth to first gas show from cable tool driller's completion reports (hereinafter sometimes referred to as "cable tooler's logs") for wells in the Price "D" Leases area shows that the top of the structure increases by about 300' from east to west across the area. A similar contour map of the base of gas shows an increase of about 150' across the area from southeast to northwest.

From a contour map of cumulative production for the Price "D" Lease area, Griffin sees no unusual producing areas such as were seen in the Flores Lease area. A relatively higher cumulative recovery is shown for wells generally along the western portion of the Price "D" Leases area. From a plot of cumulative production versus gross pay as determined from cable tooler's logs, Griffin concluded that there is no correlation between cumulative recovery and gross pay (which Griffin equated with gas in place). From a similar plot of initial potential versus gross pay as per cable tooler's logs, Griffin concluded that there is no correlation between initial potential and gross pay. Griffin did see, however, a correlation between initial potential and cumulative recovery, and concluded that cumulative recovery in the area is a function of localized permeability, rather than gas in place.

Griffin undertook to identify areas of relatively low recovery on the Price "D" Leases, for the purpose of determining where to recommend the drilling of additional wells, by preparation of a contour map of cumulative production divided by feet of gross pay. The average cumulative production divided by feet of gross pay for the Price "D" Leases is 26 MMCF per foot. Griffin considered areas with less than 30 MMCF per foot of gross pay as areas of relatively low recovery where infill drilling may be warranted. He ruled out completion techniques and water influx as explanations for low recoveries, and concluded that the areas of low recovery were the result of localized low permeability.

Griffin acknowledged that cable tooler's gross pay includes intervals potentially productive of gas (net pay) as well as intervals not potentially productive. With respect to BP's Flores Lease, Griffin considered areas with less than 60 MMCF per foot of gross pay as being within his definition of areas of low recovery, and by this standard substantially all of the Price "D" Leases would fall within a low recovery area. All of the 6 separate leases comprising what is here referred to as the Price "D" Leases have areas of low recovery as per Griffin's definition, and the areas of low recovery extend in every direction from the Price "D" Leases into the halo area of sections surrounding the Price "D" Leases.

In deciding on the proposed well locations in areas of relatively low recovery, Griffin had the objective to avoid placing a proposed location in the possible drainage area of any well having high cumulative production. To this end, Griffin mapped 3,000' circles around wells he deemed high cumulative, representing the theoretical drainage area of a well draining 640 acres, and recommended proposed well locations in the Griffin-defined low recovery area generally outside these theoretical drainage areas. No attempt was made to avoid similar theoretical drainage areas around newer replacement wells, but Griffin does not believe these replacement wells are draining 640 acres. Some of Griffin's proposed well locations had to be moved from his optimum location to avoid conflict with surface usage, such as circular sprinkler systems, or to avoid steep banks of Cold Water Creek.

Griffin decided on Rule 37 locations for proposed Well Nos. D53, D59, and D66, the W. N. Price No. 1-A, and the Price "B" No. 2 in order to place the wells in a low recovery area outside the theoretical drainage area of any high cumulative well. He decided on Rule 37 locations for proposed Well Nos. D58 and D67, and the Brannon "C" No. 2 for the same reasons and, in addition, to avoid Cold Water Creek. Rule 37 locations were recommended for proposed Well Nos. D65 and D68 to place the wells in a low recovery area outside the theoretical drainage area of any high cumulative well and avoid conflict with sprinkler systems on the surface. None of the proposed Rule 37 locations crowds the lease line of any other operator, and Griffin believes that these locations are reasonable and necessary to recover reserves that will not be recovered by any other well in the field.

(c) Economics

For the purpose of analyzing the economics of infill drilling on the Price "D" Leases, Griffin established a rate forecast for potential infill wells. By analysis of annual producing rates of replacement wells drilled on the Price "D" Leases since 1997, Griffin determined that the average initial producing rate was 154 MCF per day. He also determined an annual decline rate for these wells of 11% per year.

Using an initial producing rate of 154 MCF per day, a decline rate of 11% per year, a published gas price forecast from Sproule, a royalty burden of 12.5%, severance tax of 7.5%, incremental operating expense of $750.00 per month, and a capital investment of $225,000, Griffin calculated a 10 year undiscounted net profit per well of $625,928.

(d) Replacement Well Studies

Griffin believes that experience with drilling some replacement wells in the Price "D" Leases area is an indicator of the need for drilling additional infill wells, and sought to show this by rate versus time and shut-in tubing pressure versus time plots for 25 replacement wells, and the wells they replaced, in the Price "D" Leases area.

About two-thirds of the replacement wells studied came on at a higher producing rate than the last producing rate of the wells they replaced, and the higher rate was sustained over time for about one-half of the replacement wells studied. Some of the replacement wells with higher rates are located on the Price "D" Leases, and some are located on adjacent tracts in the halo of sections surrounding the Price "D" Leases. Of the replacement wells that came on with higher producing rates than the wells they replaced, about one-third would have been wells recommended by Griffin according to the criteria he established for recommending the locations of BP's proposed Rule 37/38 wells.

Griffin believes that some of the replacement wells that came on at higher producing rates than the wells they replaced will produce incremental reserves. He conceded, however, that the producing rate of a well, standing alone, does not establish whether the well will produce incremental reserves.

Of the 25 replacement wells studied by Griffin, pressure versus time plots showed that about 60% came on at a higher pressure than the last recorded pressure for the wells they replaced. Of these replacement wells with higher pressures, four would have been recommended by Griffin according to the criteria he established for recommending the locations of BP's proposed Rule 37/38 wells, and with time pressures in these four wells appears to have settled into a pressure profile similar to that of the wells they replaced. In all cases, the replacement wells studied by Griffin came on with pressures significantly lower than original reservoir pressure, and Griffin believes this to be the result of production by other wells. Griffin believes that the pressure data for replacement wells is less significant than producing rates because the measured pressures are counter flowing pressures. In addition, Griffin believes that reduced pressures seen in replacement wells do not rule out the possibility that the replacement wells will produce incremental reserves.

In some cases, Griffin added other nearby wells to his replacement well studies for the purpose of determining what effect, if any, replacement wells that came on with a higher producing rate had on the nearby wells. As examples, Griffin concluded that increased production by Well No. D49 had no effect on the production decline trend of nearby Well Nos. D9 and D38, and the BP Morris No. 2 had no effect on the production decline trend of the Phillips Armstrong No. 2, about 4,000' away. These and other similar examples caused Griffin to conclude that at least some of the replacement wells he studied are not competing for reserves with other nearby wells. A similar circumstance was observed by Griffin on BP's Flores Lease.

(e) Reservoir Storage/Flow Capacities

Griffin analyzed gas in place compared to the relative ability of gas to flow for 9 wells in the Griffin-defined low recovery area of the Price "D" Leases, relying on values resulting from Dr. Holmes' petrophysical analysis which employed a 5% porosity cut-off. Griffin believes that this analysis shows that the various zones, as defined by Dr. Holmes, in the Herington, Upper Krider, and Lower Krider have dramatically different properties. Griffin concludes from this analysis that in the 9 wells studied, 47.5% of the gas volume exists in Dr. Holmes' Lower Krider Zone 2, which also has 96.36% of the flow capacity seen in the wells. Griffin believes that the analysis shows that there is a significant volume of gas in the Herington, Upper Krider, and Lower Krider having very little flow capacity. The recovery factor for the Lower Krider should be much higher than for the Herington and Upper Krider. Pressure and gas left behind at abandonment should be considerably greater in the Herington and Upper Krider as compared to the Lower Krider.

From Lorenz Coefficient plots of the ability of gas to flow versus gas storage capacity for 14 wells on the Price "D" Leases and 1 additional well on a window tract interior to the leases, Griffin drew certain conclusions about pay quality in the Price "D" Leases area. Griffin concluded that for these wells, 24% of the gas in place has less than 0.1 md of permeability, 50% of the gas in place contains an average of 6% of the wells' total flow capacity, and the average Lorenz Coefficient is .69. Griffin believes that while this analysis does not necessarily indicate stratification, it does indicate significant permeability variation within each wellbore that will affect ultimate recovery.

(f) Potential for Recovery of Incremental Reserves

To support his conclusion that additional infill wells are needed to recover reserves beneath the Price "D" Leases, Griffin presented a series of pressure versus cumulative plots from which he estimated the gas being seen by wells on the leases within their drainage areas for comparison with rate versus time plots from which he estimated the gas which the wells will recover. Griffin believes that pressure versus cumulative plots enable a determination of the amount of gas that wells are seeing within their drainage areas but not a determination of the size of the wells' drainage areas. Thus, a pressure versus cumulative plot cannot be used to assist a determination of whether a well is draining an entire 640 acre proration unit. Griffin believes that rate versus time plots, either semilog or linear whichever is appropriate, enable an estimation of the volume of gas that wells ultimately will recover, based on historical production trends.

Use of pressure versus cumulative plots to estimate gas that a well is seeing within its drainage area assumes that there is no other well in the drainage area; if there is, the pressure data will deviate downward from a straight line on the plot. Absence of such downward deviation indicates that there is no other well in the drainage area. If the pressure data deviates upward from a straight line on the plot, it is the result either of energy coming into the system, such as through a water drive not known to be present in the Texas Hugoton Field, or production by the well from a multi-pressure system with the multi-pressure systems in communication at the wellbore. Where a multi-pressure system is present, normally the higher permeability zone will influence the pressure during the early life of the well, and in the latter stages of life the lower permeability zone still having higher pressure will begin to contribute more. Griffin believes that this type of performance is observed in most of the wells he has studied in the Texas Hugoton Field and on the Price "D" Leases. Griffin asserts that Phillips' expert, Dr. Richard Strickland, during a May 2000 hearing in a separate docket, observed the same dual pressure system in wells on the Discovery Operating Buzzard Lease, which lies to the northeast of the Price "D" Leases.

Griffin believes that when a well open to flow from both tight and higher permeability zones is shut-in and shut-in tubing pressure is measured, the pressure of the higher permeability zone will be measured. This is due to counterflow from the higher pressure zone into the lower pressure zone. Griffin illustrated this point by presenting measured while drilling pressure data for the Price "D" Well No. D39. This well was drilled to a depth of 2,990' in the Upper Krider where it was shut-in for 20 hours and a pressure of 187 psi was measured. The well was then drilled deeper to 3,060' in the Lower Krider where it was shut-in and a pressure of 185 psi was measured. Subsequent shut-in pressure measurement at a depth of 3,130' in the Lower Krider was 102 psi. Similar measured while drilling pressures for the Fedric No. 2, Price "D" No. D40 and Price "D" No. D41 were as follows:

Fedric #2	Price D40	Price D41
3,100' (U. Krider) 224 psi	3,140' (U. Krider) 183 psi	3,200' (L. Krider) 145 psi
3,200' (L. Krider) 143 psi	3,280' (L. Krider) 158 psi	3,300' (Winfield) 137 psi
3,300' (Winfield) 119 psi		

A formation test for the McKenzie Well No. 2-375, located about 2 miles southwest of the Price "D" Leases showed a pressure of 254 psi at a depth of 2,990' (Upper Krider), a pressure of 75 psi at a depth of 3,090' (Lower Krider), and a pressure of 65 psi at a depth of 3,170' (Lower Krider). Griffin believes this pressure data further confirms a two pressure system in the field.

Griffin accounted for the two pressure system he believed to be present in the reservoir in constructing his pressure versus cumulative plots. He concluded that plotting a straight line through early pressure date and extrapolating to zero pressure would underestimate gas that wells are seeing in their drainage areas. On his pressure versus cumulative plots, Griffin plotted a straight line through the early time pressure data and then a second intersecting straight line through the later time pressure data extrapolated to zero pressure (and, alternatively, to an abandonment pressure of 5 psi), thus to account for his interpretation of a break over in the pressure data believed to represent the effect of the dual pressure system.

Griffin presented a rate versus time plot for the entire Texas Hugoton Field which he believes shows an exponential decline during early years when wells were still reaching for their ultimate drainage areas and a linear decline in recent years after wells reached their maximum drainage areas and the decrease in flow rate was dominated by drop in reservoir pressure. An excerpt from John Lee and Robert A. Wattenberger, *Gas Reservoir Engineering*, suggests that the most common conventional decline curve analysis technique is a linear semilog decline curve, sometimes called exponential or constant-percentage decline and that most conventional decline-curve analysis is based on Arps' rate/time decline equation. Griffin believes that semilog rate versus time plots, or exponential decline curve analyses, are assumption limited. The Arps standard equation for decline curve analysis assumes that wells are produced at constant bottomhole pressure, that wells produce from unchanging drainage areas, and that wells have constant permeability and skin factor. In addition, the equation must be applied only to boundary dominated (stabilized) flow data. Griffin believes that these assumptions are not valid when applied to wells in the Texas Hugoton Field in the Price "D" Leases area.

With pore volume calculations from logs, the volume of gas in a 640 acre proration unit may be estimated. Griffin presented Dr. Holmes' volumetric calculations of original gas in place for a hypothetical 640 acres from logs for 9 replacement wells in the Price "D" Leases area (Price "D" Well Nos. D39, D41, D43, D44, D46, and D50, and W. N. Price No. 3, Brannon "C" No. 2, and Fedric No. 2) as compared with: (1) gas the original wells were seeing within their drainage areas as per pressure versus cumulative; and (2) the cumulative production of the original wells plus gas the original wells ultimately would have recovered as per linear rate versus time. For the nine wells, volumetric calculations from logs showed original gas in place of 63.78 BCF under the hypothetical 640 acre units associated with the wells. Volume of gas being seen by the original wells as per pressure versus cumulative was 45.05 BCF. Cumulative production of the original wells plus estimated remaining production as per rate versus time was 38.26 BCF.

Griffin presented pressure versus cumulative plots for all active wells in the Price "D" Leases area. These plots contained two estimates of gas being seen by the wells within their drainage areas, one based on extrapolation to zero pressure and the other based on extrapolation to a 5 psi abandonment pressure. Griffin also presented, for purposes of comparison, linear rate versus time plots for all active wells in the Price "D" Leases area for the purpose of estimating the wells' ultimate recoveries. The rate versus time plots used least squares fit of 10 years of production, 1992 through 2001, extrapolated to a zero producing rate. Griffin's estimates of gas being seen by existing wells and gas the wells will recover were posted to a map of the Price "D" Leases area, showing also the locations of BP's proposed Rule 37/38 wells. This map (BP Exhibit 78A) is attached to this Proposal for Decision as Appendix 3. Posted at the location of each existing well are Griffin's estimates of gas being seen to zero abandonment pressure (green number), gas being seen to an abandonment pressure of 5 psi (red number), and remaining recovery (blue number).

Griffin believes that his pressure versus cumulative and rate versus time plots show that none of the currently producing wells in the Price "D" Leases area will recover the volume of gas within its 640 acre proration unit. He believes also that there are no wells on tracts adjacent to BP's Price "D" Leases that will drain hydrocarbons from the tracts on which BP's proposed wells are located. While Phillips' estimates of remaining recovery by existing wells, presented to BP during prehearing discovery, are substantially greater than Griffin's, Griffin nonetheless believes that regardless of which estimates are used, they show that a minimum of 0.26 BCF of gas will be left in the ground unless BP's Rule 37/38 applications are granted.

(g) Conclusions

Griffin believes that Phillips' opposition to BP's applications is based on Phillips' policy of opposing requests for Rule 38 exceptions in the Texas Hugoton Field and Phillips' concern about demands that might be made on Phillips by royalty owners to drill additional wells if the BP applications were approved. While some Phillips wells to the east, and some wells to the south, of the Price "D" Leases have higher flowing tubing pressures than wells on the Price "D" Leases, Griffin believes that if Phillips has the concern that gas may be migrating off Phillips' tracts to BP's leases, Phillips can take steps to lower the flowing tubing pressures of its wells, for example, by installing central compression or individual wellhead compression.

Griffin concluded ultimately that: (1) BP's proposed wells are necessary to recover reserves beneath the Price "D" Leases which will not be recovered by any existing well in the field; and (2) the locations of BP's proposed wells are reasonable in light of surface considerations.

Dr. Holmes

Dr. Holmes was requested by BP to perform geological and petrophysical studies for BP's Flores and Price "D" Leases. Dr. Holmes' studies of the Texas Hugoton Field were limited to the Flores and Price "D" Leases areas and a few wells nearby. Dr. Holmes studied cores from the Buf No. 3 and Shiel 2R wells in the Guymon (Hugoton) Field in Oklahoma, and the Fee 8-209 and Bivens 16-12P wells in the Panhandle West Field. There were no cores available for study from wells in the Price "D" Leases area.

(a) Depositional Environment

The Herington and Krider formations in the Texas Hugoton Field are correlative to the Brown Dolomite in the Panhandle West Field, and these formations belong to the same depositional sequence. These rocks are Permian in age and belong to the Wolfcamp series, Chase group. The rocks were deposited in a marine environment in the areas of the Hugoton and Panhandle Fields. Dr. Holmes believes that the Hugoton Field is juxtaposed between marine environment to the east and mostly marine environment to the west. The depositional environment for the area was a shallow sea, with the area sometimes below and sometimes above sea level. Limestones were deposited when the area was covered by the sea, and when the sea regressed nonmarine siliclastics, shales, and sand were deposited, in several sequences. Worldwide sea level changes affected both the Panhandle Field and the Texas Hugoton Field areas.

The Trucial Coast of the United Arab Emirates and the Bahamas in the Andros Islands are modern analogs to the Texas Hugoton Field. In this kind of model, a wide variety of rocks are seen. Dr. Holmes believes that this could explain why some wells outperform others in a localized area.

(b) Lithology/Structure

Dolomitization occurs by percolation of supersaline solutions down through limestones. Differences in permeabilities affect percolation and result in differing degrees of dolomitization. Dr. Holmes does not believe that dolomitization in the Price "D" Leases area is as uniform as seen in the Flores Lease area. He believes the Price "D" Leases area has more limestone as compared to the Flores Lease, and the Guymon (Hugoton) and Panhandle Fields are believed to have very little, if any, limestone. There were late diagenetic processes which affected porosity. There are no available cores from wells in the Price "D" Leases area to show this, but cores from wells in the Guymon (Hugoton) show late stage anhydrite cementation which resulted in decreased porosity.

Dr. Holmes presented stratigraphic cross sections for the Price "D" Leases area to show the lithology in area wells. These cross sections were prepared from cable tool driller's logs which recorded what rocks cable tool drillers were seeing while the wells were being drilled. Picks of the various formations shown on the cross sections were based on wireline logs for nearby wells. Dr. Holmes observed considerable lateral heterogeneity in the reservoir as seen in the wells on his cross sections. The same types of rocks are present as seen in the Flores Lease, but in different proportions. Dr. Holmes observed more shale and limestones on the west side of the Price "D" Leases and more dolomite to the south and east.

Dr. Holmes concluded from his stratigraphic cross sections that the Price "D" Leases area has more limestone than the Flores Lease area and more than seen in wells in the Guymon (Hugoton) Field which he studied. The Price "D" Leases also have more shale, at least to the west, and although there are some wells having 100% dolomite, in general there is less dolomite in the Price "D" Leases as compared to the other areas which Dr. Holmes studied. Dr. Holmes believes that the reservoir beneath the Price "D" Leases is generally worse in terms of continuity and porosity development than found beneath the Flores Lease.

Dr. Holmes posted on his stratigraphic cross sections the gas shows and increases of gas recorded in cable tool driller's logs. The first record of one million cubic feet of gas varies by depth from well to well, which Dr. Holmes believes is more evidence of lateral heterogeneity of permeability. Wells on the stratigraphic cross sections are located in both low recovery and high recovery areas of the Price "D" Leases as defined by Griffin, and there appears to be no particular relationship between low recovery/high recovery areas and areas where limestone, shale, and dolomite are shown to exist. In several wells on the stratigraphic cross sections, cable tool drillers recorded significant increases in gas while drilling through limestone intervals shown on the cross sections.

Dr. Holmes also presented raw data structural cross sections prepared from wireline logs for certain wells in the Price "D" Leases area. A north-south cross section shows a gradual drop of about 120' to the top of the Herington over about nine miles from north to south, and an east-west cross section shows a drop of about 230' over about 6.5 miles from west to east. Correlation of the producing formations is shown all across both cross sections, and there is no evidence of faulting.

(c) Petrophysical Analysis

Dr. Holmes' petrophysical study was based on modern wireline logs. For the Price "D" Leases area, Dr. Holmes had available for analysis logs for about 27 wells. To establish his petrophysical model, Dr. Holmes determined shale volume by interpretation of gamma ray, calculated porosity from porosity logs, and calculated water saturation using resistivity readings from induction logs. Dr. Holmes found that rocks in the Price "D" Leases area are made up of dolomite, limestone, quartz, and anhydrite, and that rock make-up changes in proportion from well to well. The accuracy of the petrophysical model was verified using cores from three older wells which had been cored.

Dr. Holmes presented 3 stratigraphic cross sections prepared from logs for wells in the Price "D" Leases area. These cross sections were color coded to show varying degrees of porosity and V-shale from well to well. To determine net pay, Dr. Holmes used a 5% porosity cut-off, and cut-offs of 60% for water saturation and 35% for shale. Some wells are shown to have some porosity in the Herington and Upper Krider while other wells are shown to have none. Discontinuities in porosity are shown between some wells where porosity could not be correlated across the cross sections. In some cases, Dr. Holmes interpreted discontinuity where logs showed porosity at the same intervals in adjoining wells. In some cases, the character of the logs shows correlations substantially across the cross section in the Herington, Upper Krider, and Lower Krider, with some expected variations, notwithstanding discontinuity in porosity mapped on the cross sections. Isolated pods of porosity are mapped in some wells. Better lateral pay continuity is mapped in the Lower Krider as compared to the upper zones. Some wells mapped with relatively poor porosity development are in the high recovery area of the Price "D" Leases as defined by Griffin.

Dr. Holmes believes that the Price "D" Leases are different from the Flores Lease in terms of porosity development and shale content. He believes the reservoir beneath the Price "D" Leases is less continuous and has more isolated pods of porosity.

Dr. Holmes also presented a diagrammatic cross section for 3 wells on the Price "D" Lease (Price "D" Nos. D37, D49, and D38) color coded to show gas bearing porosity in various percentages. To build this cross section, Dr. Holmes interpreted the geology between wells from what he saw on well logs, mapping discontinuities between wells and some isolated pods not penetrated by any well. Dr. Holmes believes the isolated pods probably exist, but concedes that there is no wellbore evidence to support their existence. This diagrammatic cross section shows porosity which does not in all cases match porosity shown for the same wells in other cross sections presented by Dr. Holmes. The wells shown on this diagrammatic cross section are in a high recovery area of the Price "D" Leases as defined by Griffin.

A histogram presented by Dr. Holmes showed for 20 wells in the Price "D" Leases area, by stratigraphic level, the percentage of clean formation as defined in Dr. Holmes' petrophysical analysis, that is, percentage of the gross interval measured by gamma ray to have less than 35% shale volume. Variation between wells and between formations in percentage of clean formation is depicted, which Dr. Holmes believes to indicate extreme heterogeneity. Dr. Holmes believes that concentration of shales in the Upper Krider Zone 3, as he defines it, could be interrupting vertical flow of gas. Dr. Holmes' petrophysical determinations of shale do not consistently conform to rock descriptions in cable tool driller's logs, and Dr. Holmes' petrophysical model does not distinguish between shales and hot dolomite.

Dr. Holmes also presented modified stratigraphic Lorenz plots for 15 wells in the Price "D" Leases area, making petrophysical estimates of permeability calibrated from core data for the Fee 8-209 and Bivens 16-12P wells in the Panhandle West Field. These plots illustrate by depth, the percentage of storage volume versus permeability in the wells. In many wells, a high percentage of the gas is shown to be concentrated in less than 5%-10% of the total flow capacity of the wells. Considerable variability is shown both in where gas is stored and where permeability exists stratigraphically. Some wells shown to have very little gas in zones with low permeability are nonetheless in the low recovery area of the Price "D" Leases as defined by Griffin. Other wells shown to have a considerable percentage of gas tied-up in zones with low permeability are in Griffin's high recovery area.

(d) Conclusions

Overall, from his geologic and petrophysical analyses, Dr. Holmes concluded that: (1) cable tool driller's logs and/or wireline logs show lateral variability in lithology, heterogeneity in terms of depth of first gas, and a greater preponderance of shales on the western portion of the Price "D" Leases as compared to the eastern portion, the Flores Lease, and Guymon (Hugoton) wells; (2) analysis from wireline logs of porosity and gas saturation, and permeability estimates, show heterogeneity of the reservoir, both vertically and laterally, with dramatic changes of permeability and porosity over short distances; (3) existing wells are not efficiently draining the total area due to isolated porosity pods and presence of shale baffles, especially in the western portion of the Price "D" Leases; (4) as compared to the Flores Lease, the Price "D" Leases have less lateral continuity in the producing formations, and in the southeastern portion of the leases there is proportionally more gas in the Upper Krider and Herington than in the Lower Krider; and (5) while there are some good wells on the Price "D" Leases, as a whole the productivity of the Price "D" Leases is less than that of the Flores Lease

PROTESTANTS' EVIDENCE

Dr. Strickland

(a) Reservoir Continuity

Dr. Strickland confirmed that the Herington and Krider formations in the Texas Hugoton Field are correlative to the Brown Dolomite in the Panhandle Field. A core statistical summary of 10,318 core samples from the Panhandle Field shows that the Brown Dolomite in the Panhandle Field has an arithmetic mean porosity of 12.71% and geometric mean permeability of 3.52 md. This compares to BP-calculated porosities of 6.8% to 10.6% and permeabilities ranging from .46 md to 128.8 md for 9 wells in the low recovery area of the Price "D" Leases. Dr. Strickland does not believe that the BP calculated permeabilities for the 9 wells on the Price "D" Leases are realistic or valid. A Lorenz plot for the Panhandle Field taken from the 10,318 samples of the Brown Dolomite has a Lorenz coefficient of .82, indicating a moderate to high level of heterogeneity and a lot of variation in both porosity and permeability. BP's Lorenz plots for 15 wells in the Price "D" Leases area show a range of Lorenz coefficients from .48 to .82 and an average Lorenz coefficient of .69. This indicates to Dr. Strickland that Price "D" area wells do not have the same degree of heterogeneity as does the Brown Dolomite in the Panhandle Field.

Dr. Strickland observed that BP's volumetric calculations assumed that wellbore values for porosity, water saturation, and thickness were valid throughout a 640 acre section. Because the Texas Hugoton Field is heterogeneous, Dr. Strickland concluded that this assumption is not valid. Dr. Strickland agreed, however, that whenever petroleum engineers do wellbore volumetrics, an assumption is made that the wellbore parameters apply to the entire area being examined. Dr. Strickland believes that whenever volumetric calculations and pressure versus cumulative analyses are performed in connection with a field like the Texas Hugoton Field, caution must be used in drawing conclusions due to limitations of the data.

Dr. Strickland asserts that producing rate data should not be used to draw conclusions about reservoir continuity. If all other things are equal, a well with greater thickness (net pay) of the formation will have a greater rate than a well with lesser thickness. If the reservoir is continuous between wells, the wells may have very similar shut-in pressure performance with time. Dr. Strickland believes that similar pressure behavior indicates reservoir continuity between wells.

It is Dr. Strickland's view that if a replacement well is drilled and it encounters pressure that is less than original reservoir pressure, the well is drilled into the drainage area of an existing well. The reduced pressure encountered by the replacement well is another indicator of reservoir continuity.

A well's flow rate is a function of: (1) the permeability of the formation through which gas is flowing; (2) net thickness; (3) pressure out away form the well at the external boundary; (4) pressure in the wellbore; (5) completion efficiency; and (6) size of the well's drainage area, that is, how far out the pressure wave has traveled through the formation. Dr. Strickland concluded that because the Texas Hugoton Field has differences in these six variables at any location, each well's flow rate is a unique function of these variables.

Dr. Strickland observed that the formations in the Price "D" Leases area are heterogeneous. Rock properties and permeabilities vary. Because of this, flow rates and cumulatives vary among wells. Dr. Strickland believes that flow rates alone do not prove or disprove reservoir continuity. He disagrees with BP's contention that when a new well comes on with a higher producing rate than that of an old well nearby, it means that the new well has encountered a separate isolated portion of the reservoir. Further, higher producing rates of replacement wells do not indicate that the replacement wells will recover incremental reserves. There is a pressure gradient going out in the reservoir from the original well. Dr. Strickland believes that even if a replacement well is drilled in the drainage area of the original well, it starts producing at a higher rate because it has encountered higher pressure, though it shares reserves with the original well and other surrounding wells. In addition to the pressure difference, a replacement well encounters different reservoir properties. When the replacement well encounters pressure reduced from original reservoir pressure, it is drilled into the drainage area of another well, and gas that was flowing to another well turns around and flows toward the replacement well.

According to Dr. Strickland, a pressure wave of a well travels through a formation until it reaches a boundary, in the Texas Hugoton Field usually when the pressure wave collides with another pressure wave coming from another well. How far the wave travels is a function of time, permeability, porosity, type of gas-viscosity, and total system compressibility. It is the pressure wave that has traveled through the formation that causes gas to start to flow toward a well. Gas moves from high pressure to low pressure. Low producing rates do not equate to small drainage areas. Drainage areas are determined by well densities and relative rates. Dr. Strickland believes that reduced pressure in a new well indicates both reservoir continuity and drainage by other wells.

Interference between wells occurs at the boundary between wells, and Dr. Strickland observed that interference at the boundary is difficult to see in the flow rates of adjacent wells. A new well takes gas out away from an adjacent wellbore, and the effect of the new well will not be seen in the flow rate of the adjacent well when the new well comes on. Dr. Strickland believes that it is very rare for producing rates to indicate interference between wells, especially in a formation like that found in the Texas Hugoton Field. Even over a long period of time it is almost impossible to see any change in the flow rate of offsetting wells because the wells shift their drainage areas slightly due to a new well's production. Variations in normal operating conditions tend to mask the effect of a new well on the rate of adjacent wells as do low pressures and high compressibility of gas in the Texas Hugoton Field.

In Dr. Strickland's opinion, drainage areas of wells in the Price "D" Leases area cross proration unit and lease boundaries. Gas seen by a well as per pressure versus cumulative analysis is not associated with any particular tract of land; it is the gas that is associated with where pressure waves have traveled. Pressure waves and drainage occur across lease and proration unit boundaries. Dr. Strickland agrees, however, that a pressure transient stops when it hits a no flow boundary, and for a well that has an established drainage area, pressure versus cumulative analysis does not see gas beyond the point where the pressure wave stops.

Dr. Strickland presented measured while drilling pressures for 6 wells in the Price "D" Leases area (Morris #2-340, Price "D" Nos. D39, D40, D41, and D42, and Fedric #2-41). All measured pressures were in the Lower Krider or Winfield, except for a measured pressure of 157 psi in the Upper Krider in the Price "D" No. D39 and a measured pressure of 183 psi in the Upper Krider in the Price "D" No. D40. Dr. Strickland observed from these measured while drilling pressures that different pressures at different intervals are the result of reservoir heterogeneity. Some portions of the reservoir have lower permeability and over time come down in pressure slower than regions with high permeability. Dr. Strickland observed no instances of measurement of pressures while drilling, either on the Flores Lease or the Price "D" Leases, where a well encountered any portion of the formation that had original reservoir pressure. Dr. Strickland believes this is evidence that there are no isolated pods of porosity and that the reduced pressures indicate reservoir continuity. He asserts that where these wells penetrated, they encountered a portion of the formation being drained by some other well.

By use of Darcy's law, Dr. Strickland investigated whether there is vertical communication in the interwell area between the Herington, Upper Krider, and Lower Krider. For this purpose, he assumed a one square mile section of land with a formation at the top existing at a pressure of 150 psi separated from a lower formation existing at a pressure of 50 psi by a 50' intervening layer. He believed these pressures to conform to what was seen in measurement while drilling pressures for area wells and that the 50' layer of separation was analogous to what was seen in Dr. Holmes' cross sections. Using the linear form of Darcy's law, Dr. Strickland calculated that even if the layer of separation had a permeability of only .01 md, about the lowest level that can be measured in a laboratory, assuming a drop in pressure of 100 psi from the high pressure zone to the low pressure zone, 2,275 MCF of gas per day would flow vertically through the 50' separating layer. He concluded that to stop vertical flow, permeability of the separating layer would have to reach down to the order of .00001 md. According to Dr. Strickland, extremely low permeabilities are required to stop vertical flow in formations where there are pressure drops such as are seen in the measurements while drilling of wells in the Price "D" Leases area.

Dr. Strickland concluded that only extremely low permeability will stop vertical flow. He believes the only way to stop vertical flow is to have a laterally continuous shale with zero permeability. Between the Lower Krider and the Winfield is the O'Dell shale which qualifies as a laterally continuous shale with zero permeability, but absent something similar in the upper zones, Dr. Strickland believes that there is vertical flow between the Herington, Upper Krider, and Lower Krider. He believes also that the reduced measured while drilling pressures for wells in the Price "D" Leases area and the reduced pressures observed in replacement wells are the result either of lateral flow to a wellbore or vertical flow. Dr. Strickland asserts that this has implications on depletion of the upper zones in that they are being depleted by vertical flow down into a lower pressure zone.

Dr. Strickland presented semilog rate versus time plots and pressure versus time plots for 65 Phillips replacement wells in the Texas Hugoton Field. He observed that none of these wells encountered original reservoir pressure, which indicates to Strickland that the wells were drilled into areas being drained by other wells.

Dr. Strickland also observed that of the 28 replacement wells drilled on 25 different sections in the Price "D" Leases area, none encountered original reservoir pressure, again indicating to him that these replacement wells were drilled into the drainage areas of existing wells. Dr. Strickland believes that the reduced pressures which these wells encountered are the result of either lateral or vertical flow. That some of these wells came on a higher rate than that of the wells they replaced means to Dr. Strickland that the replacement wells were drilled in areas with better porosity and permeability, but the fact that the pressures observed in these wells were depleted means that the gas was on its way to being produced by another well. Dr. Strickland does not believe that higher rates seen in replacement wells means that the wells will produce incremental reserves. Although the wells with higher rates may produce more gas than the original wells would have produced, this does not, in Dr. Strickland's view, equate to incremental recovery since the reduced pressures mean that the gas was already on its way to some other well.

Dr. Strickland concedes that when a well open to zones with differing pressures is shut-in and pressures are measured, the measured pressures reflect the pressure in the higher permeability zone. The Texas Hugoton Field in the Price "D" Leases area has variable pressures at different spots, and it is hard to say what pressure exists in any one formation when wells are completed over large vertical intervals.

Dr. Strickland presented a series of isobaric maps of the Price "D" Leases area dating from 1966 through 2001, indicating shut-in wellhead pressures at one point in time. The isobaric maps show that over time pressures have fallen from high to much lower pressures. Drainage areas of wells have changed over time. Dr. Strickland believes that the isobaric maps show that the entire area of the Price "D" Leases is in pressure communication. He asserts that BP's proposed Rule 37/38 wells will be drilled into areas which isobaric mapping shows have already been drained by existing wells. Dr. Strickland believes that there is virtually no chance that an infill well drilled in the Price "D" Leases area will find commercial reserves that are not currently in the drainage area of an existing well.

Dr. Strickland also presented pressure versus time plots for wells in the Price "D" Leases area. He believes that these plots show similar pressure versus time behavior for all area wells. An arrow map presented by Dr. Strickland showed his interpretation of pressure communication between wells in the Price "D" Leases area. Dr. Strickland concluded that these studies indicate pay continuity across the Price "D" Leases.

Stick cross sections were presented by Dr. Strickland for certain wells on the Price "D" Leases, showing completion intervals and the relative locations of BP's proposed Rule 37/38 wells. The cross sections were selected to span wells on either side of the proposed locations, and these east-west cross sections covered the Price "D" Leases from north to south. The gross interval of the Herington and Krider formations are shown to be relatively constant. In general, wells in the Price "D" Leases area are completed in the Herington, Upper Krider, and Lower Krider, and sometimes through the O'Dell shale into the Winfield. Dr. Strickland observed that BP's proposed Rule 37/38 wells will be drilled in areas where the surrounding wells are completed throughout the producing formations. He believes this supports his conclusion that the proposed wells will encounter reserves that are currently in the drainage areas of existing wells.

(b) Studies of Remaining Reserves

Dr. Strickland estimated remaining recoveries of reserves for a total of 72 wells in the Price "D" Leases area. This compared to Griffin's calculation of remaining recoveries for 87 wells. For some wells, Dr. Strickland did not have sufficient data from which to extrapolate reserves.

Dr. Strickland estimated remaining recoveries for the 72 wells he was able to study by plotting rate versus time on a semilog scale. This is the methodology which Dr. Strickland uses when calculating the remaining reserves to be recovered by wells from rate/time decline curve type analysis. This is an exponential decline, which Dr. Strickland believes will continue into the future. According to Dr. Strickland, Phillips and Travelers use this exponential decline methodology, plotting monthly production on a semilog scale and extrapolating into the future to determine reserves, and Dr. Strickland believes that BP uses the same methodology as evidenced by exponential decline curves furnished to Phillips during prehearing discovery. Dr. Strickland estimated that the 72 wells he studied will recover a total of 38.379 BCF of remaining reserves. Dr. Strickland presented several examples comparing his estimates of remaining recoveries by particular wells with estimates made by Griffin. In all of the examples given, Dr. Strickland's estimates of remaining recoveries were substantially higher than those made by Griffin.

Dr. Strickland disputes BP's position that use of Arps' exponential decline curve analysis for estimating remaining recovery of reserves by wells in the Price "D" Leases area of the Texas Hugoton Field violates assumptions underlying the Arps equation. The assumption that bottomhole pressures are constant means that if such pressures are exactly constant and nothing else changes, historical production will be a perfect straight line on a semilog plot. In reality bottomhole pressure fluctuates slightly with wellhead pressure and as compressors come on or go off. Dr. Strickland does not believe that wells in the Price "D" Leases area violate the constant bottomhole pressure assumption.

The Arps equation also assumes that drainage areas have fixed boundaries, and Dr. Strickland agrees that drainage areas of individual wells in the Texas Hugoton Field change. However, the data will display a bowed character when a well is reestablishing its drainage area, and one using the Arps analysis needs to be aware of this and be out beyond the bow when using an exponential fit of the data. Dr. Strickland concludes that this is no major violation of the assumptions underlying the Arps equation.

In the Texas Hugoton Field, permeability at wellbores is essentially constant. Even if there is a change in the completion efficiency of a well, the well goes back to the long term decline when the completion efficiency problem is resolved. Thus, Dr. Strickland sees no violation of the constant permeability and skin factor assumption underlying the Arps equation.

When a well is not in boundary dominated stabilized flow, it has a hyperbolic looking decline. In Dr. Strickland's opinion, wells in the Price "D" Leases area get to boundary dominated flow so that they easily can be fit with an exponential decline. Dr. Strickland sees no violation of the boundary dominated stabilized flow assumption underlying the Arps equation.

Dr. Strickland believes that wells producing in the Texas Hugoton Field, especially wells in the Price "D" Leases area, are excellent examples of wells that do not violate any of the four assumptions for Arps exponential decline curve analysis. Use of this analysis, as articulated in John Lee and Robert A. Wattenberger, *Gas Reservoir Engineering*, develops a substantially larger prediction of future production than the linear extrapolation employed by Griffin. To an economic limit the exponential reserves are about twice the linear reserves. Using the methodology recommended by Lee and Wattenberger for exponential decline curve analysis, Dr. Strickland recalculated Griffin's linear reserves as per rate versus time for Dr. Strickland's 72 study wells in the Price "D" Leases area in two ways: (1) taking the log of the rate for least squares fit and extrapolating for the same number of years Griffin used to show linear time; and (2) extrapolating to an approximate economic limit. For the 72 wells, Griffin estimated reserves of 19.4 BCF. Changing the calculation to a semilog exponential analysis for the same time period used by Griffin yielded reserves of 26.4 BCF. Extrapolating to an approximate economic limit yielded 42.5 BCF.

In the opinion of Dr. Strickland, pressure versus cumulative methodology should not be used to calculate reserves that wells are seeing within their drainage areas in the Price "D" Leases area due to variability and uncertainty in the pressure data. In a high permeability reservoir that is a depletion drive, the gas material balance equation works well, and the solution to the equation can be graphically represented by a plot of pressure divided by the gas deviation factor (Z) versus the cumulative production. The data is supposed to line up in a straight line, allowing extrapolation of the historical pressure data as a straight line. Extrapolating the P/Z down to zero gives a value for initial gas in place, and the difference between the last measured point and abandonment is a measure of reserves to be produced in the future.

Griffin's pressure versus cumulative analyses are hand extrapolations of pressure data for wells in the Price "D" Leases area. Dr. Strickland concluded that he could arrive at virtually any answer he wanted by extrapolation of the same data. In his opinion, the data set is not of a quality to determine reserves from pressure versus cumulative. He believes that it is extremely difficult to say that pressure versus cumulative for Price "D" Leases wells develops reserves yet to be produced or even reserves being seen in the wells' drainage areas. Dr. Strickland says that there are multiple ways to extrapolate the data that give a multitude of answers.

Dr. Strickland presented pressure versus cumulative plots for the Price "D" Well Nos. D1, D3, D9, D19, D23, D29, D31, and D32, the Devon Spurlock #1, and the L. M. Price #1 to demonstrate numerous different interpretations of how the data could be extrapolated to estimate reserves. Different trend lines are displayed depending on how the lines are drawn through the data. Depending on how the trend line is drawn through the data, the various interpretations displayed on Dr. Strickland's plots predict the following range of reserves for the study wells:

Well	Range of Estimates
Price "D" #D1	0.514 BCF to 1.229 BCF
Price "D" # D3	0.323 BCF to 1.689 BCF
Price "D" #D9	0.458 BCF to 2.042 BCF
Price "D" #D19	0.322 BCF to 1.553 BCF
Price "D" #D23	0.298 BCF to 1.593 BCF
Price "D" # D29	0.188 BCF to 1.318 BCF
Price "D" # D32	0.332 BCF to 2.667 BCF
Price "D" # D31	0.369 BCF to 1.376 BCF

Dr. Strickland believes that these various examples of different interpretations as to how the data might be extrapolated support his view that the pressure versus cumulative method should not be used to calculate reserves, due to variability and uncertainty in the pressure data and the multiple trend lines that can be drawn through the data. Dr. Strickland concedes that pressure versus cumulative has some usefulness in the Texas Hugoton Field and may be a measure of what a well sees within its drainage area. He has a problem, however, with the method of extrapolation of the data and the drawing of a conclusion about the physical existence of gas. Dr. Strickland believes that Phillips uses a semilog rate versus time methodology for reserve analysis, and uses pressure versus cumulative as a check against rate/time. Based on the prehearing deposition of a BP reservoir engineer (Matcek), he does not believe that BP uses pressure versus cumulative to calculate reserves.

Dr. Strickland compared rate versus time estimated ultimate recovery as compared with pressure versus cumulative reserves wells are seeing as calculated by BP. For the Price "D" Leases, rate versus time reserves are 24% of pressure versus cumulative reserves. For the halo of sections around the Price "D" Leases, rate versus time reserves are 17.4% of pressure versus cumulative reserves.

(c) Conclusions

Overall conclusions reached by Dr. Strickland are: (1) studies on reservoir continuity and reserves show that the subject reservoir is heterogeneous, and it should not be expected that wells will have the same flow rates or cumulative production; (2) studies of replacement wells show that no replacement well has found original reservoir pressure, indicating that all replacement wells have been drilled into the drainage area of an existing well; and (3) there is no chance that the 20 proposed Rule 37/38 wells will encounter commercial reserves that are not currently in the drainage area of an existing well. In Dr. Strickland's opinion, the proposed wells are not necessary.

EXAMINERS' OPINION

BP requests exceptions to Statewide Rule 38 for a total of 20 wells on its subject leases, and exceptions to Statewide Rule 37 for 7 of these wells. BP contends that granting of the requested exceptions is necessary to prevent waste and to prevent confiscation.

An applicant seeking exceptions to Statewide Rule 38 based on prevention of waste must establish three elements: (1) that unusual conditions, different from conditions in adjacent parts of the field, exist under the tracts for which the exceptions are sought; (2) that, as a result of these unusual conditions, hydrocarbons will be recovered by the wells for which exception permits are sought that would not be recovered by any existing well or by additional wells drilled at regular locations; and (3) that the volume of otherwise unrecoverable hydrocarbons is substantial. An applicant seeking exceptions to Statewide Rule 38 to prevent confiscation must show that: (1) it is not possible for the applicant to recover its fair share of minerals under its tracts from regular locations; and (2) that the proposed irregular locations are reasonable.

An applicant seeking exceptions to Statewide Rule 37 also has the burden to show that the exceptions are necessary to prevent waste or to prevent the confiscation of property. As with Rule 38 exceptions, where Rule 37 exceptions are sought based on the prevention of waste, the applicant must show unusual conditions and that no regular location is available which will satisfy the goal of preventing waste. An owner of oil and gas is entitled to an opportunity to recover the reserves underlying his tracts, and any denial of that opportunity amounts to confiscation. *Atlantic Refining Co. v. Railroad Commission*, 346 S.W.2d 801 (Tex. 1961); *Imperial American Resources Fund, Inc. v. Railroad Commission*, 557 S.W.2d 280 (Tex. 1977). When the subject tract is capable of supporting a regular location, the applicant for a Rule 37 exception based on confiscation must prove that the proposed irregular location is necessary because of surface or subsurface conditions and that the proposed location is reasonable. To do this, the applicant must show that it is not feasible to recover his fair share of the oil or gas under his tract from regular locations. A mineral interest owner's fair share is measured by the currently recoverable reserves under his property.

An applicant who undertakes the burden of showing that Rule 37/38 exceptions are necessary to prevent waste due to unusual conditions must show conditions underlying the tracts on which the exception well is sought to be drilled different from those in the adjacent area or the part of the field in which the tract is situated. *Hawkins v. Texas Company*, 209 S.W.2d 338, 342-343 (Tex. 1948). The conditions affecting the drainage of wells on the particular tract for which exceptions are sought must be so peculiar, unusual and abnormal that the tract is removed from the same category of the surrounding area to which the general rule applies. When these peculiar and unusual conditions are found to exist in a localized area, exceptions may then be granted for the drilling of additional wells to the extent necessary to offset the abnormality and place the subject tract on parity, from the standpoint of efficient drainage, with other areas where ordinary and usual reservoir conditions prevail. *Wrather v. Humble Oil & Refining Company*, 214 S.W.2d 112, 117 (Tex. 1948). Exceptions based on prevention of waste must be based on actually known or ascertainable conditions at the time the Commission acts, and not upon the bare possibility that conditions warranting the exceptions might later develop or come to light. *Marine Production Co. v. Shell Oil Co.*, 165 S.W. 2d 934, 936 (Tex.Civ.App.-Austin 1942, writ ref'd w.o.m.).

Based on the entirety of the evidence in the record, the examiners conclude that BP failed to prove that the requested Rule 37/38 exceptions are necessary to prevent waste or to prevent confiscation.

BP did not prove that the granting of Rule 37/38 exceptions are necessary to prevent waste because BP did not show that conditions underlying the subject leases are so peculiar, unusual, and abnormal as to set them apart from the adjacent area or part of the field in which the leases are situated. The first and most obvious difficulty presented by BP's evidence bearing on this issue is the scarcity of proof of conditions in other portions of the Texas Hugoton Field with which to compare conditions existing beneath the Price "D" Leases, or, more particularly, the "low recovery" area of the Price "D" Leases where BP's Rule 37/38 wells are proposed to be drilled.

The studies by BP's experts of the subject field, as they related to the "unusual conditions" issue, were for the most part limited to BP's Price "D" Leases, BP's Flores Lease about four miles to the south, and a "halo area" of sections around the Price "D" Leases and Flores Lease. More limited testimony was presented regarding BP's Cartrite Lease, which lies between the Price "D" Leases and the Flores Lease, and the Discovery Operating Buzzard Lease which lies to the northeast of the Price "D" Leases. BP's evidence regarding the Cartrite and Buzzard Leases tended to show similarity of conditions, rather than differences, between these leases and the Price "D" Leases. No real attempt was made by BP to distinguish conditions underlying the Price "D" Leases from those underlying the "halo" of tracts surrounding the Price "D" Leases. Some comparisons were made in BP's evidence to the Buf No. 3 and Shiel 2R wells in the Guymon (Hugoton) Field in Oklahoma and the Fee 8-209 and Bivens 16-12P wells in the Panhandle West Field, but these selective comparisons of wells in other fields do not distinguish conditions beneath the low recovery area of the Price "D" Leases from conditions in other parts of the Texas Hugoton Field.

BP argues that its evidence proved "unusual conditions" beneath the Price "D" Leases in terms of permeability, anomalously low recoveries, depositional environment, and lithology, but the examiners fail to see how this is so. Some effort was made to distinguish conditions beneath the Price "D" Leases and the Flores Lease to the south, but overall the evidence shows more essential similarities than differences. The arguments now made for a finding of "unusual conditions" beneath the Price "D" Leases are not materially different from those made previously in support of a similar requested finding for the Flores Lease.

There is evidence that there is heterogeneity and variation of permeability, in the Texas Hugoton Field and in the portion of the reservoir underlying the Price "D" Leases. The literature which is in evidence pertaining to general geology of the Panhandle-Hugoton District suggests that local variations in permeability are *common* in the Texas Hugoton Field, Panhandle Field, Guymon

(Hugoton) Field, and Kansas Hugoton Field. The Herington and Krider formations in the Texas Hugoton Field are correlative to the Brown Dolomite in the Panhandle Field, and the Panhandle Field is shown to be at least as, if not more, heterogeneous than the reservoir beneath the Price "D" Leases.

There is evidence that while there are some good wells on the Price "D" Leases, as a whole the productivity of the Price "D" Leases is less than that of the Flores Lease. However, low cumulative recoveries by some wells on the Price "D" Leases do not prove unusual conditions in the reservoir that are different from conditions existing elsewhere in the Texas Hugoton Field. The Flores Lease also had older wells with varying cumulatives, some relatively high and some relatively low, and also had areas of relatively low and relatively high recovery as defined by BP. In addition, relatively low cumulative recoveries and current rates of wells on the Price "D" Leases do not appear to distinguish the Price "D" Leases from the adjacent areas of the Texas Hugoton Field, as is evidenced by BP's mapping of cumulative recoveries and daily rates for wells in the "halo" of sections surrounding the Price "D" Leases.

There is no persuasive evidence that the environment in which rocks were deposited beneath the Price "D" Leases was significantly different from the depositional environment in the Flores area, and no serious contention is made that it differed from the depositional environment for rocks beneath the halo of tracts surrounding the Price "D" Leases. The exhibits presented by Dr. Holmes to describe the depositional model of the Price "D" Leases were the same as presented to show the depositional model of the Flores Lease. Mapping shows essentially the same marine and/or mainly marine environments encompassing and surrounding the Panhandle and Hugoton Fields from the Texas Panhandle all the way north into Kansas. Worldwide sea level changes affected both the Panhandle Field and Texas Hugoton Field areas.

BP made no apparent attempt to prove that lithology in the reservoir beneath the Price "D" Leases differs from lithology beneath the adjacent tracts which surround the Price"D" Leases. Since no cores were available for wells in the Price "D" Leases area, or for that matter anywhere in the Texas Hugoton Field, BP's description of area lithology was based either on cable tool driller's descriptions or petrophysical analysis. Dr. Holmes testified that the same rocks are present beneath the Price "D" Leases as are beneath the Flores Lease, although in different proportions. Dr. Holmes analyses were to the effect that there is more shale on the western portion of the Price "D" Leases and more limestone generally as compared to the Flores Lease, but this does not establish that shale and limestone are not also present beneath the Flores tracts or that similar proportions of shale and limestone do not exist in other portions of the Texas Hugoton Field or, in particular, beneath the tracts that surround the Price "D" Leases (in fact, the evidence suggests the contrary).

BP contends that it has shown that existing wells, or additional wells drilled at regular locations, will not recover the hydrocarbons currently in place beneath the Price "D" Leases. The examiners have concluded that there is insufficient reliable proof that this is so, but even were BP's comparison of reserves as determined by pressure/cumulative with estimated remaining recoveries as determined by linear rate/time deemed probative, this evidence does not distinguish the low recovery area of the Price "D" Leases, as defined by BP, from the area of relatively higher recovery on these leases or from the adjacent area of the Texas Hugoton Field consisting of the "halo" of sections around the Price "D" Leases. BP's contention is that wells in the "halo" area will not recover the reserves beneath this area either.

BP asserts that it was not required to prove that conditions underlying the Price "D" Lease are unusual or unique as compared to conditions beneath the "halo" of sections surrounding the Price "D" Leases. This argument appears to conflict with the holdings in *Hawkins v. Texas Company, supra* and *Wrather v. Humble Oil & Refining Company, supra*, which require, to support a finding of waste, a showing of unusual conditions as compared to the *adjacent* area or *surrounding* area of the field. Moreover, if BP were correct that similarity of conditions beneath the "halo" of sections surrounding the Price "D" Leases is irrelevant, BP's "unusual conditions" theory could not stand by reason of BP's failure to prove conditions in any *other* part of the Texas Hugoton Field, other than the Flores Lease, for purposes of comparison.

BP's applications cannot be approved on either a waste or confiscation theory because: (1) BP did not prove that substantial hydrocarbons will be recovered by the wells for which exception permits are sought that would not be recovered by any existing well or by additional wells drilled at regular locations; and (2) BP did not prove that the requested exception permits are necessary to enable BP to recover its fair share of hydrocarbons underlying the subject tracts.

The examiners are not persuaded by BP's argument that a reasonable basis exists in the evidence to conclude that BP's proposed Rule 37/38 locations will enable BP to recover substantial hydrocarbons that otherwise will go unrecovered. These locations were determined first by defining an area of "low recovery" on the Price "D" Leases. The "low recovery area," as defined by BP, was determined by dividing cumulative production of older wells by feet of *gross* pay indicated by cable tool driller's logs. The soundness of this approach is drawn into question by at least two factors: (1) BP's own proof shows that there is no correlation between cumulative production and cable tool driller's gross pay; and (2) the assumption that every foot of cable tool driller's gross pay contains gas is unfounded, since BP conceded that cable tool driller's gross pay consists of both productive and nonproductive intervals. The proposed locations were selected with a view toward avoiding the presumed 640 acre drainage radius of older wells, but no effort was made to avoid a similar drainage radius of newer replacement wells.

There appears to be no direct correlation between the proposed well locations and BP's calculations of reserves as determined by pressure versus cumulative compared with estimated remaining recoveries as determined by linear rate versus time. BP contends that wells on the Price "D" Leases and in the "halo area" will not recover the reserves beneath these areas regardless of whether they are "low recovery" or "high recovery" by BP's definition. Stratigraphic cross sections presented by BP show that some wells with good porosity development are nonetheless in an area of low recovery as defined by BP, and some wells with relatively poorer porosity development are in an area of high recovery. Lorenz plots presented by BP show that some wells with very little gas tied up in areas of low permeability are nonetheless in the BP-defined low recovery area, while other wells which BP contends have a lot of gas tied up in areas of low permeability are in the BP-defined high recovery area.

BP did not persuasively establish that existing wells on the Price "D" Leases are not efficiently and effectively recovering the recoverable gas in place beneath these leases. The limited number of conventional electric logs available for wells on the Price "D" Leases precluded BP from constructing and presenting a net pay isopach map and from performing a conventional pore volume analysis for the leases as a whole. BP presented volumetric calculations from logs for 9 replacement wells on the Price "D" Leases, but Rule 38 wells are proposed on only 3 of the proration units or same 640 acre sections of land where these 9 replacement wells are located. These volumetrics for hypothetical 640 acre areas have limited usefulness here in that: (1) they assume that wellbore values are uniform throughout 640 acres in a reservoir that is heterogeneous and which is described by BP's experts as having widely varying properties over short distances; and (2) they are unrelated to any particular proration unit or tract of land.

There are some variations in thickness of the Herington and Krider formations across the Price "D" Leases, but gross pay as reflected by cable tool driller's logs is continuous across the leases and BP claimed no significance to greater thickness of the formations on the western side of the leases as compared to the eastern side. In general, wells in the Price "D" Leases area are completed in the Herington, Upper Krider, and Lower Krider formations, and BP's Rule 37/38 wells are proposed to be drilled at locations which are surrounded by existing wells completed throughout these formations.

No faulting or other major geological event is seen in the formations beneath the Price "D" Leases. Dolomite, a rock with relatively good porosity and permeability, is pervasive across the leases. Limestone is also present, indicating some degree of selective dolomitization, but cable tool driller's logs reported significant increases in gas while drilling through intervals classified by BP as limestone. Some shale is also present, particularly in the western portion of the leases, but cumulative production of wells in the western portion of the leases is also relatively high. Dr. Holmes picks of shales in wells on the subject leases include silt having some permeability, and there is insufficient evidence to conclude that in the area of the Price "D" Leases there are continuous shale barriers to vertical flow between the Herington, Upper Krider, and Lower Krider formations.

Available logs show relatively good correlations of porosity over several miles, in some cases all across stratigraphic cross sections presented by BP. Interpretations of discontinuities in porosity mapped by BP are constrained by the limited log data and well control which is available. Some wells shown by BP's cross sections to have relatively poor porosity development are nonetheless in an area of high recovery as defined by BP. There is relatively little evidence to support BP's theory that there are isolated pods of porosity having original reservoir pressure beneath the Price "D" Leases that have no communication with existing wellbores. The reservoir appears to be reasonably continuous and in pressure communication across the Price "D" Leases.

Most of the wells in the Texas Hugoton Field, including most wells on the Price "D" Leases were drilled in the 1940's or early 1950's, and the field is now in the latter stages of depletion. Isobaric maps of the Price "D" Leases area for the period 1966 through 2001 indicate that over time pressures in the reservoir have dropped significantly, and pressures in the entire area are now very low. According to this mapping, drainage areas of wells have changed over time, and the isobaric maps tend to show that the entire area is in pressure communication. Isobaric mapping tends to show also that BP's proposed Rule 37/38 wells will be drilled into areas where pressure has been depleted by existing wells.

Available measured while drilling pressures for wells in the Price "D" Leases area also show pressure depletion in the reservoir, even in the Herington and Upper Krider which are tighter zones where over time pressures come down slower than in zones with higher permeability. There are no demonstrated instances of measurement of pressures while drilling where a well encountered any portion of the formations that had original reservoir pressure.

The experts seem to agree that when a well open to zones with differing pressures is shut-in and pressures are measured, the measured pressures reflect the pressure in the higher permeability zone. Even so, of the 28 replacement wells drilled in the Price "D" Leases area, and of the 65 replacement wells drilled by Phillips throughout the Texas Hugoton Field, none is shown to have encountered original reservoir pressure, and the initial pressures measured in such wells were significantly reduced from original reservoir pressure. The conclusion is warranted that the depleted pressures seen in measured while drilling pressure data and in replacement wells is the result either of vertical flow or lateral flow to another wellbore, and all replacement wells appear to have been drilled into the drainage area of another well.

Pressure versus time plots presented by Phillips for wells in the Price "D" area show similar pressure versus time behavior for all area wells, a further indicator of pay continuity and pressure communication across the area.

The fact that some of the existing wells on the Price "D" Leases have lower producing rates than others, and thus lower cumulatives, does not necessarily mean that the reservoir beneath these leases is not continuous and in pressure communication. The reservoir is heterogeneous, and rock properties and permeabilities vary. Wells have different producing rates because they have different permeabilities, thicknesses of formations, pressures at external boundaries, completion efficiencies, and drainage areas.

The initial producing rates of replacement wells do not necessarily say much about reservoir continuity. Nor do higher initial producing rates of replacement wells as compared to the last producing rates of the wells they replaced necessarily prove that the replacement wells will recover incremental reserves. In most cases, a replacement wells is drilled because there is a problem with the original well, so that, in general, replacement wells should be expected to have higher rates. In addition, a replacement well may encounter different reservoir properties. There is a pressure gradient going out in the reservoir from the original well, and even if the replacement well is drilled in the drainage area of the original well, it will start producing at a higher rate because it has encountered higher pressure, though it shares reserves with the original well and other surrounding wells. A replacement well may produce more gas than the original well would have produced, but this does not necessarily mean that the replacement well is producing reserves that would have gone unrecovered by any other well, particularly where the pressure measured in the replacement well is significantly depleted from original reservoir pressure.

The fact that a replacement well had no apparent effect on the production decline trend of an older adjoining well does not necessarily prove that the replacement well is producing from a separate source of supply. Interference between wells occurs at the boundary between wells and is difficult to see in the flow rates of adjacent wells. A new well takes gas out away from an adjacent wellbore, and the effect of the new well may not be seen in the flow rate of the adjacent well when the new well starts to produce. Even over a long period of time it is difficult to see any change in the flow rate of offsetting wells because the wells shift their drainage areas slightly due to the new well's production. Variations in normal operating conditions tend to mask the effect of a new well on the flow rate of adjacent wells as do low pressures and high compressibility of gas in the Texas Hugoton Field.

BP contends that pressure versus cumulative plots for existing wells on the Price "D" Leases, indicating reserves that the wells are seeing within their drainage areas, as compared with rate versus time plots estimating the remaining reserves the wells will recover, show that the proposed Rule 37/38 wells are needed to recover reserves that will not be recovered by any existing well. The examiners conclude, however, that BP's pressure/cumulative and rate/time studies are not sufficiently reliable to establish that this is so.

There is some conflict in the evidence as to whether use of pressure versus cumulative extrapolation is commonly used to estimate reserves in the Texas Hugoton Field. A Phillips reservoir engineer (Shirley) stated in a prehearing deposition that he had used this methodology, but Mr. Griffin testified that Phillips also uses rate versus time plots to book reserves. Mr. Griffin also testified that he did not know whether BP uses pressure versus cumulative to determine reserves in this field. A BP reservoir engineer (Matcek) testified in a prehearing deposition that he used rate versus time decline curve analysis, rather than pressure versus cumulative, to determine reserves for leases in the Texas Hugoton Field. Dr. Strickland testified that Phillips uses a semilog rate versus time methodology for reserve analysis and uses pressure versus cumulative as a check against rate/time.

BP's and Phillips' experts appear to agree that while pressure versus cumulative analysis may enable some estimate of gas being seen within a well's drainage area, this type of analysis says nothing about the size of the drainage area. Pressure versus cumulative analysis does not serve to estimate gas in place beneath a 640 acre proration unit or beneath any particular tract of land. If a well's drainage area extends across a lease line, estimates of reserves derived from pressure versus cumulative may include some portion of reserves beneath an adjacent lease, and pressure versus cumulative analysis for a particular well does not necessarily furnish a reliable estimate of reserves under that well's proration unit. Pressure versus cumulative may be useful in estimation of reserves, but caution must be used in drawing conclusions by reason of limitations on this type of analysis.

Uncertainty or variability in available pressure data, and the fact that only limited pressure data may be available for particular wells, makes it difficult to estimate reserves from pressure versus cumulative analysis. How to draw a trend line through the pressure data on pressure versus cumulative plots to extrapolate reserves is interpretive and the subject of more than one theory about methodology. BP's estimates of gas being seen by wells on the Price "D" Leases are derived from Mr. Griffin's hand extrapolations of the available pressure data, based on his interpretation of how the trend line should be drawn through the pressure data on pressure versus cumulative plots. Dr. Strickland's analysis of these plots shows that there are multiple different, and plausible, interpretations of how the trend line should be drawn through the data, which lead to reserve estimates significantly lower than BP's estimates.

Considerable doubt also exists about the reliability of BP's rate versus time estimates of remaining reserves that existing wells on the Price "D" Leases will recover. BP's rate versus time recovery estimates for existing wells are forecast with a linear decline instead of with an exponential decline. The most common conventional decline curve analysis technique is a semilog decline curve based on Arps' rate/time decline equation, a decline which is exponential in form. Use of BP's linear decline technique tends to substantially underestimate recovery of reserves for existing wells on the Price "D" Leases, as is demonstrated by Dr. Strickland's analyses plotting rate versus time on a semilog scale.

While the Arps exponential decline curve technique is assumption-based, the examiners conclude that the assumptions underlying this technique are not so violated in the case of the reservoir and wells in the Price "D" Leases area as to make BP's linear decline curve technique more suitable for estimating remaining recoveries. BP contends that the evidence shows that existing wells on the Price "D" Leases will not recover the reserves beneath the leases regardless of whether BP's linear rate/time technique or Phillips' exponential rate/time technique is used. The examiners do not agree with this contention because it assumes the reliability of BP's pressure versus cumulative estimates of gas which existing wells are seeing, and the reliability of these estimates is not well established in the evidence.

BP did not reliably prove the amount of recoverable gas in place beneath the Price "D" Leases or beneath the BP-defined low recovery area of the leases where the proposed Rule 37/38 wells will be located. Neither did it convincingly prove that existing wells are not efficiently and effectively draining the reservoir beneath the Price "D" Leases. BP makes no claim that gas is being drained from the Price "D" Leases by wells on adjoining tracts. As is the case with the Price "D"

Leases, the surrounding tracts have only one producing well per 640 acres. Pressures on surrounding tracts to the east are higher than pressures in the adjoining area of the Price "D" Leases, which may be causing some gas to migrate toward the Price "D" Leases. BP's own pressure/cumulative and rate/time analyses suggest that existing wells on the Price "D" Leases will recover a greater percentage of the gas the wells are seeing within their drainage areas than will wells on the "halo area" tracts surrounding the Price "D" Leases. BP did not prove that the proposed Rule 37/38 wells are necessary to enable BP to recover its fair share of hydrocarbons beneath the Price "D" Leases.

Because BP failed to prove that the requested Rule 37/38 exceptions are necessary to prevent waste or to prevent confiscation, the examiners recommend that the applications be denied. Based on the record in these dockets, the examiners recommend adoption of the following Findings of Fact and Conclusions of Law.

FINDINGS OF FACT

1. At least ten (10) days notice of the hearing in these dockets was sent to all parties entitled to notice.

2. BP America Production Company ("BP"), formerly Amoco Production Company, seeks exceptions to Statewide Rule 38 for a total of 20 wells on its Price Et Al., Brannon "C", W. N. Price, Price, Price "B", and Sweny Leases (hereinafter referred to collectively as the "Price 'D' Leases"), Texas Hugoton Field, Sherman County, Texas. Exceptions to Statewide Rule 38 are requested to drill 15 wells on the Price Et Al. Lease, and 1 well on each of the Brannon "C", W. N. Price, Price, Price "B" and Sweny Leases.

3. BP also requests exceptions to Statewide Rule 37 for 7 of the proposed wells on the Price Et Al. Lease and for the proposed wells on the Brannon "C", W. N. Price, Price, and Price "B" Leases.

4. The wells proposed to be drilled by BP, their proposed locations, and reasons why Rule 37 and/or Rule 38 exceptions are required are as set forth in Appendix 1 to this Proposal for Decision, which is incorporated into this finding by reference.

5. Field rules for the Texas Hugoton Field provide for spacing of 1,250 feet from any property line, lease line or subdivision line and 2,500 feet from any well on the same tract completed in or drilling to the same horizon. The field rules also provide for 640 acre density.

6. The Price "D" Leases now have the maximum number of producing wells permitted by the 640 acre density rule governing the Texas Hugoton Field.

7. The BP applications for exceptions to Statewide Rules 37/38 are opposed by Phillips Petroleum Company ("Phillips"), an operator of offsetting tracts to the northeast, east,

southeast, south, west, and northwest of the Price "D" Leases, and Travelers Oil Company ("Travelers"), an operator of an offsetting tract to the northwest of the Price "D" Leases.

8. The Texas Hugoton Field was discovered in 1918. It lies immediately to the north of the Panhandle West Field and covers the northern portion of Moore County, most of Sherman County, and the western portion of Hansford County.

9. As of the date of the March 26, 2002, Oil and Gas Proration Schedule, there were 910 wells in the Texas Hugoton Field. Most of these wells were drilled in the 1940's or early 1950's.

10. The Texas Hugoton Field has producing formations that correlate to the Brown Dolomite in the Panhandle West Field.

11. Wells on the Price "D" Leases generally encounter three potentially productive formations in the Texas Hugoton Field, the Herington, the Upper Krider, and the Lower Krider. There are some completions in the Winfield formation on the Price "D" Leases, but much of the porosity in the Winfield is water bearing.

12. Wells on the Price "D" Leases and in adjacent and surrounding areas encounter predominantly dolomite in the Herington, Upper Krider, and Lower Krider formations. Limestone, quartz, anhydrite, and shales are encountered in some wells.

13. The Lower Krider formation has higher permeability and better porosity than do the more shallow Herington and Upper Krider formations. There is good lateral communication and wide drainage in the Lower Krider in the area of the Price "D" Leases.

14. There is reservoir continuity and interwell communication among wells on the Price "D" Leases and the adjacent or surrounding area.

    a. Continuity and communication are not interrupted by faulting or other geological condition.

    b. Porosity intervals correlate over distances of several miles in the producing formations, particularly in the Upper Krider and Lower Krider.

    c. Adjoining wells on and in the area of the Price "D" Leases have similar pressures, all of which are substantially depleted from original reservoir pressure.

    d. Pressure performance over time of wells on the Price "D" Leases has been similar.

    e. Differences in flow rates and cumulative production of wells on the Price "D" Leases and adjacent areas do not necessarily indicate a lack of reservoir continuity or lack of interwell communication. Wells may have different producing rates because they have different permeabilities, thicknesses of formations, pressures at external boundaries, completion efficiencies and drainage areas.

15. Existing wells on the Price "D" Leases are effectively and efficiently draining the Herington, Upper Krider, and Lower Krider formations in the Texas Hugoton Field.

    a. Original reservoir pressure in the Texas Hugoton Field was about 450 psi. Measured pressures in 2001 on the Price "D" Leases ranged from 14 psi to 70 psi.

    b. Historic and current isobaric maps for the area of the Price "D" Leases show uniform decline in pressure over time, as wells have drained the reservoir.

    c. Pressures of adjoining wells on the Price "D" Leases and surrounding tracts have declined similarly over time with effective areal drainage.

    d. Twenty-eight replacement wells drilled on 25 different sections in the Price "D" Leases area encountered pressures depleted from original reservoir pressure. None of these replacement wells encountered original reservoir pressure.

    e. Measured while drilling pressures taken in the Upper Krider and Lower Krider in six wells drilled in 1996-1998 in the Price "D" Leases area were significantly reduced from original reservoir pressure. These pressures ranged from 50% down to 8% of original reservoir pressure at various intervals.

    f. Existing wells on the Price "D" Leases generally are completed throughout the Herington, Upper Krider, and Lower Krider formations.

    g. The Herington, Upper Krider, and Lower Krider formations beneath the Price "D" Leases are being depleted by vertical communication between formations and/or by completions in existing wells.

16. BP did not prove that its proposed Rule 37/38 wells will recover a substantial volume of hydrocarbons that would not be recovered by any existing well or by additional wells drilled at regular locations.

    a. Existing wells are effectively and efficiently draining the reserves beneath the Price "D" Leases.

    b. Higher initial producing rates of replacement wells do not establish that the replacement wells will recover reserves that otherwise would go unrecovered by any other existing well.

c. BP's pressure versus cumulative estimates of gas that existing wells are seeing as compared to rate versus time recovery estimates for existing wells do not reliably forecast the need for additional wells to recover incremental reserves.

i. Pressure versus cumulative estimates of gas that existing wells are seeing within their drainage areas do not define the size of drainage areas or necessarily estimate reserves beneath any particular tract of land or proration unit.

ii. Usefulness of pressure versus cumulative extrapolations to estimate reserves is limited by the amount of pressure data available for analysis and by uncertainty and variability in the pressure data.

iii. Pressure versus cumulative extrapolations are subject to error in interpretation. There are multiple plausible interpretations as to how to draw the trend line through pressure data on pressure versus cumulative plots, with widely varying estimates of reserves depending upon the interpretation selected.

iv. Rate versus time recovery estimates forecast by BP with a linear decline, as opposed to an exponential decline, tend to underestimate future recovery by existing wells.

d. Limited availability of conventional electric logs for wells on the Price "D" Leases precluded BP from performing a comprehensive conventional pore volume analysis for the leases as a whole.

17. BP did not show that peculiar, unusual, or abnormal conditions exist in the subject reservoir beneath the Price "D" Leases as compared to adjacent and surrounding parts of the Texas Hugoton Field.

a. Studies of the Texas Hugoton Field performed by BP's experts primarily were limited to the areas of BP's Price "D" Leases and the Flores Lease. More limited analysis was made of BP's Cartrite Lease and the Discovery Operating Buzzard Lease.

b. Geological studies of the Price "D" Leases area do not show any faulting in the area.

c. Conditions beneath the Cartrite and Buzzard Leases are similar to those existing under the Price "D" Leases.

d. Conditions beneath the Price "D" Leases are similar to those existing beneath the Flores Lease and tracts adjacent to and surrounding the Price "D" Leases.

e. Heterogeneity and variations in permeability do not distinguish conditions beneath the Price "D" Leases as unusual.

i. Local variations in permeability are common in the Texas Hugoton Field, Panhandle Field, Guymon (Hugoton) Field, and Kansas Hugoton Field.

ii. The Herington, Upper Krider, and Lower Krider formations in the Texas Hugoton Field are correlative to the Brown Dolomite in the Panhandle Field, and the Panhandle Field is at least as, if not more, heterogeneous than the reservoir beneath the Price "D" Leases.

f. Flow rates and cumulative production of wells on the Price "D" Leases do not distinguish the conditions beneath these leases as unusual.

i. Variations of flow rates and cumulative production of wells exist on the tracts adjacent to and surrounding the Price "D" Leases and on the Flores Lease.

ii. The BP-defined low recovery area on the Price "D" Leases extends in every direction into the area of the field adjacent to and surrounding the Price "D" Leases.

g. The depositional environment in which rocks were deposited under the Price "D" Leases did not differ from the depositional environment in which rocks were deposited under the Flores Lease or the tracts adjacent to and surrounding the Price "D" Leases.

h. BP did not prove that lithology as seen in wells on the Price "D" Leases distinguishes these leases from tracts adjacent to and surrounding the Price "D" Leases. Although there are proportional differences in some wells, the rock types under the Price "D" Leases are the same as those beneath the Flores Lease.

i. BP's claim based on pressure versus cumulative and rate versus time extrapolations that existing wells will not recover all the gas they are seeing within their drainage areas applies both to wells on the Price "D" Leases and to wells on tracts adjacent to and surrounding the Price "D" Leases.

18. BP's proposed wells are not necessary to enable BP to recover its fair share of the hydrocarbons under the Price "D" Leases.

a. Volume of gas in place beneath the Price "D" Leases is not established.

i. BP's estimates of the volume of gas existing wells are seeing within their drainage areas are not the same thing as gas in place beneath any particular tract of land or proration unit.

ii. BP did not establish the reliability of pressure versus cumulate estimates of reserves in this area of the field given variability in the pressure data and the multiple plausible interpretations which can be made of the manner in which the trend line should be drawn through the data to extrapolate reserves.

iii. Insufficient logs were available to enable BP to estimate gas in place by volumetric calculation for the Price "D" Leases or the BP-defined low recovery area of these leases as a whole.

iv. BP's volumetric calculations of original gas in place from logs for 9 wells relate to an undefined 640 acres that does not coincide with any particular tract or proration unit and are based on an assumption that wellbore values extend out over an entire 640 acres notwithstanding heterogeneity in the reservoir in this area.

b. BP is capable of recovering currently recoverable reserves beneath the Price "D" Leases from existing wells.

c. Tracts offsetting the Price "D" Leases are drilled to the same density in the subject reservoir as are the Price "D" Leases.

d. Wells on offsetting tracts are not draining reserves from the Price "D" Leases.

e. Lower pressures in the eastern portion of the Price "D" Leases as compared with pressures on offsetting tracts may cause gas to migrate from the offsetting tracts to the Price "D" Leases.

f. Existing wells on the Price "D" Leases will recover a greater percentage of the gas the wells are seeing within their drainage areas than will wells on offsetting tracts according to BP's pressure/cumulative and rate/time analyses.

19. Denial of the requested Rule 37/38 exceptions will not cause waste of a substantial volume of hydrocarbons that will not be recovered by any existing well.

20. Denial of the requested Rule 37/38 exceptions will not deny to owners of the Price "D" Leases an opportunity to recover the reserves underlying the Price "D" Leases.

CONCLUSIONS OF LAW

1. Proper notice of hearing was timely given to all persons legally entitled to notice.

2. All things have occurred and been accomplished to give the Commission jurisdiction to decide this matter.

3. BP is required to obtain exceptions pursuant to Statewide Rule 38 to the field rules regarding well density in order to drill the applied-for wells.

4. BP is required to obtain exceptions pursuant to Statewide Rule 37 to the field rules regarding spacing in order to drill the proposed Price Et Al. Lease Well Nos. D53, D58, D59, D63, D65, D66, and D67, the Brannon "C" Lease Well No. 2, the W. N. Price Lease Well No. 1A, the Price Lease Well No. 68, and the Price "B" Lease Well No. 2.

5. Approval of the requested exception permits is not necessary to give owners of the Price "D" Leases a reasonable opportunity to recover their fair share of hydrocarbons in the Texas Hugoton Field underlying the Price "D" Leases, or the equivalent in kind.

6. Approval of the requested exception permits is not necessary to prevent the waste of a substantial volume of hydrocarbons in the Texas Hugoton Field.

7. Exceptions to Statewide Rules 37 and 38 for wells at the applied-for locations are not necessary to prevent confiscation or to prevent waste.

RECOMMENDATION

The examiners recommend that the subject applications be denied in accordance with the attached final order.

Respectfully submitted,

James M. Doherty

James M. Doherty
Hearings Examiner

Donna K Chandler

Donna Chandler
Technical Examiner